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Aggregate modeling of fast-acting demand response and control under real-time pricing

David P. Chassin [a,b,*], Daniel Rondeau [a]

[a] University of Victoria, Victoria, BC, Canada
[b] SLAC National Accelerator Laboratory, Menlo Park, CA, USA

HIGHLIGHTS

- Demand elasticity for fast-acting demand response load under real-time pricing.
- Validated first-principles logistic demand curve matches random utility model.
- Logistic demand curve suitable for diversified aggregate loads market-based transactive control systems.

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ABSTRACT

This paper develops and assesses the performance of a short-term demand response (DR) model for utility load control with applications to resource planning and control design. Long term response models tend to underestimate short-term demand response when induced by prices. This has two important consequences. First, planning studies tend to undervalue DR and often overlook its benefits in utility demand management program development. Second, when DR is not overlooked, the open-loop DR control gain estimate may be too low. This can result in overuse of load resources, control instability and excessive price volatility. Our objective is therefore to develop a more accurate and better performing short-term demand response model. We construct the model from first principles about the nature of thermostatic load control and show that the resulting formulation corresponds exactly to the Random Utility Model employed in economics to study consumer choice. The model is tested against empirical data collected from field demonstration projects and is shown to perform better than alternative models commonly used to forecast demand in normal operating conditions. The results suggest that (1) existing utility tariffs appear to be inadequate to incentivize demand response, particularly in the presence of high renewables, and (2) existing load control systems run the risk of becoming unstable if utilities close the loop on real-time prices.

1. Introduction

In 2003 Economics Nobel Laureate Vernon Smith published an editorial with Lynne Kiesling in the Wall Street Journal [1] summarizing the consensus in the wake of the California Electricity crisis. In their view the crisis was in part precipitated by the lack of customer engagement in electricity pricing mechanisms [2]. Reflecting on the technical and regulatory supply-side response to the crisis, they wrote "What is inadequately discussed, let alone motivated, is the [other] option – demand response". It is now widely accepted that demand response can mitigate the market power of energy suppliers. More importantly, demand response presents a real opportunity for improvement in electricity planning and operations. Research on short-term demand response in particular has increased as the growth of intermittent wind and solar resources further exacerbates the problem of managing the balance between supply and demand in power systems [3].

Historically, demand response programs have taken the form of so-called "demand side management" (DSM) activities. DSM seeks to alter electricity demand load shapes to make them better match the available supply and reduce load peaks so as to defer costly capacity expansion investments. Traditional DSM programs include increased building and appliance efficiency standards, as well as equipment replacement/retrofit programs.

* Corresponding author at: SLAC National Accelerator Laboratory, Menlo Park, CA, USA.

E-mail addresses: dchassin@slac.stanford.edu (D.P. Chassin), rondeau@uvic.ca (D. Rondeau).

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Load shifting has also long been recognized as a second approach to modulate demand response. Whereas traditional energy efficiency programs aim to reduce overall consumption, load shifting focuses specifically on changing the time of day when energy is used in order to favor times when costs are lower. Programs that focus on load shifting typically require mechanisms such as time-of-use (TOU) pricing or real-time pricing to induce transient changes in consumer behavior, such as those described by Vardakas [4]. TOU and seasonal rates focus on the customer's response to simple static price signals [5]. The Electric Power Research Institute (EPRI) carried out a major study of the top five experiments in the United States in the early 1980s and concluded that consumers responded to higher prices by shifting some of their load to off-peak periods [6]. Later experiments produced similar results. The City of Anaheim Public Utilities conducted a residential dynamic pricing experiment and found that for a peak-time rebate of \$0.35/kW h they could reduce electricity use by 12% during critical-peak days [7]. California's Advanced Demand Response System pilot program used a critical peak pricing (CPP) tariff using the GoodWatts system to obtain peak reductions as high as 51% on event days with a CPP rate and 32% on non-event days with TOU rate. Enabling technology was identified as an important driver for load reductions [8]. This observation was also made in the Olympic Peninsula Project, where both TOU and real-time price (RTP) tariff were tested [9]. Similar results over a large number of studies have been widely reported and are summarized in a survey published by Faruqui et al. [8].

Since the introduction of *homeostatic utility control* by Schweppe et al. [10], it has been understood that key system state variables such as frequency and voltage in large-scale interconnections could be regulated using price signals. Prices have since been used primarily to schedule and dispatch generation resources using power markets [11]. Both energy efficiency programs and time-of-use rates have consistently been shown to effectively reduce loads on time-scales greater than one hour [12].

To avoid unfair pricing in the presence of demand response, David et al. [13] and later Kirschen et al. [14] examined how the elasticity of demand could be considered in wholesale scheduling systems. Initial work applying market-based mechanisms to building control systems showed that the notion of market-based demand control was feasible and effective for more granular systems [15]. The general concept of transactive control was initially proposed [16,17] as a method of coordinating very large numbers of small resources using market-like signals at the electricity distribution level. The theory is essentially the same as for wholesale markets. However, realizations can be quite different insofar as more frequently updated price signals are typically used to manage distribution system constraints such as feeder capacity limits. These prices can dispatch both distributed generation, energy storage and demand response resources at much higher temporal and physical granularity than is possible with wholesale markets.

A number of previous studies have considered the operational impact of using retail price signals for controlling load in electric power systems. Glavitsch et al. [18] showed that nodal pricing could find a socially optimal operating point for power markets. Following up on this work Alvarado [19] considered the question of whether power systems could be controlled entirely using prices, and found that price signals could indeed work. But the results came with some caveats, the most significant of which is the question of stability of the feedback control over the entire system.

The feasibility of transactive control methods has been proven out through a number of field demonstrations of automated distributed generation. The 2007 Olympic Peninsula demonstration [20] and the 2013 Columbus Ohio demonstration [21] are two examples of demand response control systems that dispatch distribution-level resources in quasi real-time using price signals. These experiments yielded a trove of high-resolution data about the behavior of load resources in response to short-term price variations.

Overall, two important lessons have been learned from decades of utility research, development, and field experimentation with demand response [4]:

1. Consumer interest and sustained participation is essential to the success of demand response programs. Too many programs showed too little consumer interest and participation. This drives up program costs and reduces effectiveness. Tools to keep customers engaged and responsive to utility priorities are needed. Substantive contract diversity and meaningful incentives need to be available for customers to choose and actively engage in programs.
2. Programs should not provide rewards and incentives on the basis of complex baseline or reference models. Mechanisms that provide or enable endogenous sources of counter factual prices and quantities should be preferred by utilities.

Although transactive systems are similar to wholesale markets, the price signals are applied to different resources, affect consumer needs differently and are applied at much higher temporal and physical granularity than is possible in wholesale markets. Short-term consumer response to price variations is also understood to be quite distinct from long-term demand response. Long-term demand response is typically associated with changes in consumer behavior and the conversion to more energy efficient houses and appliances.

On the other hand, short-term demand response is primarily in the form of time-shifting and often requires automation. Short term demand response can be very different from long-term demand response because controllable load resources can be quickly exhausted, leading to control saturation. As a result, short and long term consumer responses are not generally comparable. In practice, long-term demand response models tend to underestimate the magnitude of the controllable resources and overestimate their endurance [20,21]. This has two important consequences: (i) Planning studies tend to undervalue the potential contribution of short-term demand response system and is often overlooked in utility program development; and (ii) when it is not overlooked, the open-loop control gain is underestimated, resulting in over-control, instability and excessive price volatility.

The lack of solid theoretical basis for short-term performance claims has emerged as a significant challenge [22,23]. Using static long-term own-price elasticities can be expected to give rise to erroneous short-term demand response control because short-term elasticities are more often substitution elasticities where the substitute is obtained in time rather than by an alternative product, a distinction which was made evident by Fan's study of Australian price elasticities [24], among others. Own-price elasticities represent averages over long periods of time. These averages may fail to capture the magnitude and variability possible at any given time. For example, Reiss and White [25] developed a household electricity demand model for assessing the effects of rate structure change in California and found that a small fraction of households respond to the price changes with elasticities range as large as -2, which far exceeds the average long-term elasticity of -0.14 found in Faruqui's survey of DR programs [12]. Unfortunately, computing the elasticity of demand for short-term demand response to real-time prices has proved challenging because the counterfactual price and demand are difficult to determine in the absence of a short-term feedback signal that elucidates the loads'